Modelling of a power-to-gas system to predict the levelised cost of energy of an advanced renewable gaseous transport fuel.

Shane McDonagh[1,2,3], Richard O'Shea[1,2,3], David M Wall[1,2], Paul Deane[1,2], Jerry D Murphy[1,2*]

[1]*MaREI Centre, Environmental Research Institute, University College Cork, Ireland*
[2]*School of Engineering, University College Cork, Ireland*
[3]*Gas Networks Ireland, Cork, Ireland*

Abstract

Power to gas (P2G) is proposed as a means of producing advanced renewable gaseous transport fuel whilst providing ancillary services to the electricity grid through decentralised small scale (10MW) energy storage. The study uses a discounted cash flow model to determine the levelised cost of energy (LCOE) of the gaseous fuel from non-biological origin in the form of renewable methane for various cost scenarios in 2020, 2030, and 2040. The composition and sensitivity of these costs are investigated as well as the effects of incentives and supplementary incomes. The LCOE was found to be €107-143/MWh (base value €124) in 2020, €89-121/MWh (base value €105) in 2030, and €81-103/MWh (base value €93) in 2040. The costs were found to be dominated by electricity charges in all scenarios (56%), with the total capital expenditure the next largest contributor (33%). Electricity costs and capacity factor were the most sensitive parameters followed by total capital expenditure, project discount rate, and fixed operation and maintenance. For the 2020 base scenario should electricity be available at zero cost the LCOE would fall from €124/MWh to €55/MWh. Valorisation of the produced oxygen (€0.1/Nm_3 profit) would generate an LCOE of €105/MWh. A payment for ancillary services to the electricity grid of €15/MW_e for 8500h p.a would lower the LCOE to €87/MWh. Price parity with diesel, exclusive of sales tax, is achieved with an incentive of €19/MWh.

Keywords: Power-to-gas, sensitivity analysis, LCOE, energy storage, hydrogen, methane

Corresponding Author: jerry.murphy@ucc.ie

1. Introduction

The Paris agreement (under COP21) has set a target of limiting the increase in global temperatures to less than 2°C. To facilitate this, an 80% reduction in greenhouse gas (GHG) emissions by 2050 will most likely be required [1,2]. The reduction in GHG emissions will rely on decarbonisation of the energy sector and a push for sustainable energy solutions to meet increasing energy demand through leverage of existing and future technologies.

As transmission system operators (TSO) aim to facilitate targets set under the Renewable Energy Directive (RED), renewable technologies will be prioritised [3]. The ensuing decarbonisation of the energy system will increase the amount of variable renewable electricity (VRE) on the electricity grid. Increasing portions of variable renewable electricity will pose challenges for the grid with regards to balancing, stability, and periods where supply exceeds demand [4,5]. Thus, the storage, flexibility, and balancing capabilities will need to increase with increased VRE installed capacity, to ensure the reliability and safe operation of electricity supply [6,7]. Additional flexibility and grid stability requirements to facilitate increasing shares of VRE have been previously discussed in literature [4,5,8]. The task of matching supply with demand can lead to periods of curtailment, inefficient production, and potentially affect security of supply [7,9,10]. Large scale and flexible energy storage options are seen as a means of reducing these effects [11].

Storage of otherwise curtailed electricity has typically been achieved through pumped hydroelectric storage (PHS) systems. PHS is a mature technology with a worldwide installed capacity of 143 GW, but is restricted by geography [12–14]. Other technologies such as compressed air energy storage and battery storage have also been mooted as important storage mechanisms in future electricity networks. Power-to-Gas (P2G) is an emerging technology that can utilise otherwise curtailed electricity and convert it to hydrogen (H_2) via electrolysis of water. The hydrogen can then be further combined with carbon dioxide (CO_2) to produce methane (CH_4) via a Sabatier reaction. The ability of P2G to absorb excess electricity and remove the requirement to “turn off” electricity power plants or “spill” renewable electricity facilitates VRE and allows for the provision of ancillary services [15]. It has been proposed as a means of storing excess electricity, adding stability to the electricity grid, and producing a substitute for natural gas [11,16,17]. Operating ideally, P2G facilitates higher shares of indigenous wind, wave, and solar energy offsetting the need for energy imports and abating GHG emissions [18,19]. A significant advantage of P2G as a form of energy storage is the change of the energy carrier from electricity to gas (either hydrogen or methane). Converting electrical energy into chemical energy allows for large-scale storage through existing gas grid infrastructure [6].

P2G systems (when the vector is methane) have superior storage capacities and discharge times to that of PHS through use of the natural gas grid [20]. For instance, the French national gas grid alone

has a capacity of over 100TWh [21]. P2G does not require favourable geography nor large infrastructural changes in countries with existing gas networks [11]. Gaseous fuel from non-biological origin produced by P2G is designated as an advanced third-generation biofuel; such advanced biofuels are heavily promoted within the EU framework due to their low land use change, potentially low carbon intensity, and waste to energy/circular economy characteristics. Transport fuel suppliers are obliged to provide an increasing share of advanced renewable transport (excluding first generation biofuels from food crops), rising from 1.5% in 2021 to 6.8% in 2030. At least 3.6% of this must be from advanced biofuels (including gaseous fuel from non-biological origin) [22]. Gaseous fuel from P2G, injected to the natural gas grid, could thus be used as an advanced transport fuel in natural gas vehicles (NGVs) and in conjunction with guarantees of origin provide the required 70% emissions reduction as compared to the fossil fuel displaced (required by the RED and proposed amendments to ensure sustainability of biofuels beyond 2021) [23–25].

The state of the art in LCOE of P2G (methane) systems may be viewed in Table 1. A number of technology reviews of P2G with respect to working principles, relative advantages and disadvantages, and trends in technology have been provided in past literature [7,15,26–29]; estimates of system costs have also been detailed [15,26,30–33]. However, much uncertainty still remains with cost estimates varying substantially [6,28,30,32,34–36] from €75 to €600/MWh CH_4. It is the view of the authors' that anticipated cost reductions in the literature have not materialised to the extent predicted. The concept that electricity that would have been curtailed being available at a low-cost is not reflective of current electricity market data [26,37]. The innovation in this paper is that it advances upon previous cost estimates using a discounted cash flow model of the lifetime of a plant which accounts for maintenance costs and frequency, commissioning/decommissioning, fixed and variable operational expenditure and maintenance (OPEX), and real-world electricity market data. It also uses a plant lifecycle that optimises the replacement schedule of the components and the latest cost estimates for these.

Table 1. State of the art in LCOE of P2G systems

LCOE (€/MWh CH_4)	**Assumptions (Year of reference)**	**Run hours**	**Electricity cost**	**Reference**

		(p.a.)	(€/MWh)	
600	Integration with a lignite power plant. 80MW_e input. (2012)	1200	N/A	Buchholz et al. [38]
190 – 316	Heat and O_2 utilisation not included. (2014)	3000	25	E&E Consultants [21]
132 – 245	Biological methanation as novel upgrading. Compression and grid injection (2016)	N/A	50	Vo et al. [39]
141 – 236	Heat and O_2 utilisation not included. (2013)	8600	45	Benjaminsson [26]
210	Coupled with 5 MW biogas production. No heat or O_2 valorisation. (2014)	3000	50	Graf et al. [37]
185	10MW_e input. Tax free electricity. Compression and injection included. (2015)	7800	60	ENEA [31]
170	10MW_e input. Tax free electricity. Compression and injection included. (2015)	8600	40	ENEA [31]
92 - 113	Heat and O_2 utilisation not included. (2050)	3000	25	E&E Consultants [21]
95	10MW_e input. Tax free electricity. Compression and injection included. (2015)	6100	15	ENEA [31]
75	Revenue of €10/tonne O_2 included. (2015)	5000	50	Vandewalle et al. [30]

The objectives of the paper are to:

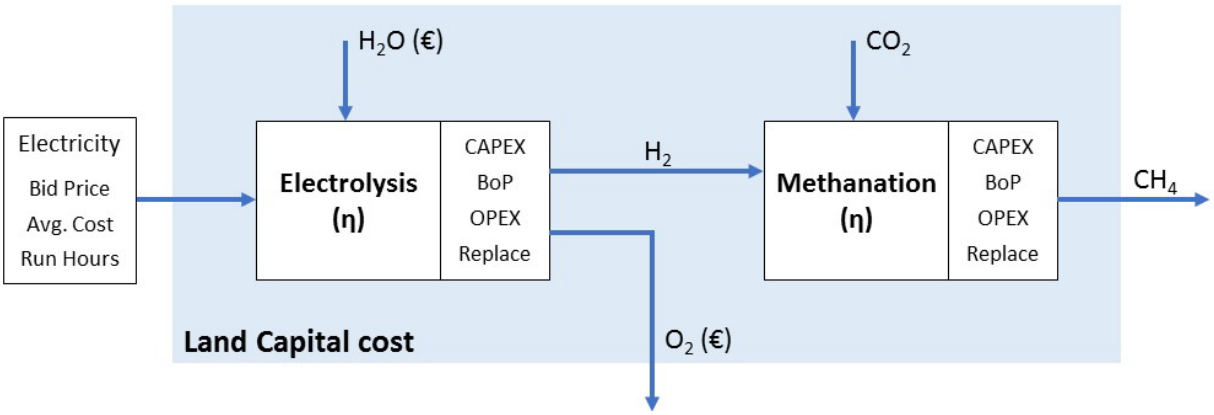
- Assess the most appropriate technologies (electrolysis and methanation), and their associated specifications for use in a P2G system.
- Create a bespoke model that calculates the levelised cost of energy (LCOE) for P2G systems for a range of inputs, scenarios, and time periods.
- Investigate the relationships between various parameters and system LCOE through sensitivity analysis and examination of the cost composition of these.
- Calculate the required incentives to reach price parity with diesel as a transport fuel, and the effect sale of oxygen (produced through electrolysis) or grid services may have on LCOE.

2. Methodology

2.1 The Power-to-Gas (P2G) system

In this study, P2G is defined as the combination of electrolysis, to produce hydrogen, and methanation, to generate methane (by reacting carbon dioxide with hydrogen). In the envisaged system, the methane could be compressed and injected into the natural gas grid. It was also considered that the operation of the P2G plant may require temporary storage of hydrogen.

Estimates for the variables outlined in Figure 1 and used in the model are based upon an extensive literature review and are referenced appropriately. Where several estimates existed, or there were large differences in the quoted values, average figures were calculated and used. Similarly, where estimates were found for time periods different to those being investigated, figures were extrapolated backward or forward. It is postulated that this method of avoiding the use of a single set of figures minimises the risk of over or under accounting for costs specific to one piece of research, and allows for more accurate approximations of component costs and performance. Values in currency other than Euro were converted using a currency converter [40] and corrected to 2016 euros using inflation calculators [41,42]; as such the results are reported as 2016 Euro.



BoP (Balance of plant); OPEX (operational cost); Capex (cost of capital) Replace (replacement of components during plant life). Calculation of Land Capital cost (equation 4) is detailed in Appendix 1.

Figure 1. Inputs and variables included in the model to calculate the LCOE of the produced gaseous fuel.

2.1.1 Electrolysis

Electrolysis is the key enabling technology for P2G. It is a mature technology with commercial electrolysers already available on the market. Electrolysis allows for the conversion of electrical energy and water, into hydrogen and oxygen (O_2), as in equation 1.

$$2H_2O \xrightarrow{yields} \Leftrightarrow 2H_2 + O_2 \quad (1)$$

Producing hydrogen through the dissociation of water occurs in the electrolysis cells. Though this may vary slightly depending on the technology, each cell generally contains water, electrodes, and an electrolyte material crossed by an electric current. Hydrogen and oxygen are produced separately, at the cathode and anode respectively. The electrolyte material ensures the transfer of ions from one section (typically referred to as a cell) to the other, which are separated by a membrane. The cell size is limited by the ability of the membrane to withstand the electric current.

Electrolysis cells are therefore piled into stacks that make up the core of an electrolyser and hence are somewhat modular [31]. Each unit also contains a water pump and cooling system, electrical auxiliaries, hydrogen purification, and instrumentation. The removal of impurities damaging to the electrolysis cells can be achieved either by systems within the unit or by a centralised system and distributed to each electrolyser. More thorough descriptions of the process can be found in past literature [26,27,43,44].

Electrolysis only accounts for a small proportion of the world's hydrogen production due to the associated high investment and operating costs, and relative low-cost of the steam reforming of natural gas [43]. However, for future decarbonised energy systems "green" hydrogen from "surplus" renewable electricity is required for sustainability. The three technologies examined further in this paper are alkaline electrolysis cells (AEC), proton exchange membrane (PEM) electrolysis, and solid oxide electrolysis cells (SOEC). They represent the most suitable electrolysis systems for P2G now and in the future.

2.1.2 Alkaline electrolysis cells (AEC)

As of 2015, AEC was the state-of-the-art electrolyser and the only available electrolysis technology suitable for large scale P2G applications with several manufacturers positioning themselves as potential providers for the P2G market [31]. AEC can operate at atmospheric or elevated pressures and uses an aqueous alkaline solution (NaOH or KOH) as the electrolyte to transfer electrons through hydroxide anions as needed to dissociate the water. Depending on the scale and operating conditions the efficiency of AEC varies between 66% and 74%; the system can operate at loads of 10-150% for limited times, and has a restart time of 10-60 minutes [31,35]. High maintenance costs can potentially occur due to the corrosive nature of the alkaline solutions [15]. Although continuously developing, increases in system performance are likely to be marginal given the existing maturity of AEC. Additional cost reductions can come from market growth (with maximum reduction envisaged at 10 to 20 % of the final price). Similar reductions can be assumed in the required capital expenditure (CAPEX) due to technical innovations [7,15,31]. A more detailed assessment of the current and future capabilities of AEC has been outlined in past literature [7,15].

2.1.3 Proton exchange membrane (PEM)

PEM electrolysis is a more recently developed technology that is currently used in small scale applications in industrial markets. However, PEM electrolyser manufacturers are very active in the development of the technology for P2G applications with demonstration units operating up to 2MW [7,26,31,37]. The technology uses proton transfer polymer membranes that act as both the

electrolyte and the separation material between the different cells of the electrolysis stack. PEM can operate at atmospheric pressure, and is also capable of operating at higher pressures than AEC [6]. The quoted efficiencies for PEM vary between 67 and 82% with future advances beyond this expected [7,35]. In terms of suitability to P2G, PEM electrolysis offers very fast shut down and start up times from both transient and cold operation, a part load range of 5-100%, and higher purity hydrogen [45,46]. Long-term degradation of the cells is a technical barrier to commercialisation of this technology, however improvements are expected [7,35].

In the choice between PEM and AEC electrolysers there exists a trade-off between system efficiency and cost. Given the technological improvements being made and the rates at which they are occurring for the respective technologies, for a given specification, a point will be reached where the performance of PEM surpasses AEC. PEM electrolysers currently have higher CAPEX than AEC due to lower technology readiness level (TRL). However, further development of the technology is expected to reduce investment costs significantly, to below that of AEC. It is also expected that PEM will soon technically outperform AEC and thus become the more dominant technology for P2G systems [6,7,37].

2.1.4 Solid oxide electrolysis cells (SOEC)

SOEC, also known as high temperature electrolysis, is considered a future electrolysis technology for P2G systems. It is still at an early stage of development with the investment costs yet to be distinguished. No commitment to producing MW scale units in the medium term has been made [26,31]. SOEC operates at high temperature (700-800°C) using ceramic materials for both the electrolyte and electrode materials; the high temperature reduces the electrical input required for the water to dissociate. The significant advantage of SOEC technology is its high efficiency (typically 80 to 90%). The high temperatures also limit the systems flexibility as they are not stable against fluctuating or intermittent power [15,47]. The biggest challenge to the viability of SOEC is the fast material degradation and limited long term stability of operation [48].
Future integration with an exothermic reaction (for instance, catalytic methanation) would allow for heat recovery to produce steam for the electrolysis stack and could theoretically lead to efficiencies above 100% [47]. However, at present, SOEC is considered to be at a low TRL [21,31,49].

2.2 Methanation

The methanation phase for P2G refers to the reaction between carbon dioxide and hydrogen, in a Sabatier process as described by equation 2.

$$CO_2 + 4H_2 \xrightarrow{yields} \Leftrightarrow CH_4 + 2H_2O\ (g) \quad -164kJ.mol^{-1} \qquad (2)$$

The equilibrium of the reaction is influenced by pressure and temperature. In thermodynamic equilibrium, high pressures favour the production of methane whilst high temperatures limits production.

The reaction is thermodynamically limited to 74% efficiency (LHV: CH_4 (10.494 kWh/m^3) / (4 x H_2(3.543 kWh/m^3)) and is highly exothermic; thus there is potential for the utilisation of waste heat. Two methods of methanation are possible, biological and catalytic; neither technology can be considered mature in the application to P2G. Comprehensive reviews of both can be found in literature [15] as well as details of ongoing and completed P2G projects [29].

2.2.1 Biological methanation

Biological methanation (BM) is a process whereby methane is produced using hydrogenotrophic methanogenic archaea that consume both hydrogen and carbon dioxide. The reaction is anaerobic and takes place in an aqueous solution, at atmospheric pressure, at temperatures between 20 and 70 °C [29,31]. BM has the potential to be a lower cost option due to simple reactor designs, low pressures, and low temperatures [21]. BM can be in-situ (using the existing methanogenic archaea present in an anaerobic digester) or ex-situ (reaction takes place in an external vessel specifically inoculated with methanogenic archaea). For P2G applications the high gas flow rates, mixing requirements, required purity, and controllability make the ex-situ process more suitable [26]. However, several barriers to higher efficiencies exist for ex-situ BM. The solubility of hydrogen in the reaction medium is greatly hindered by the gas-liquid interface. This is addressed by higher mixing rates which increases the parasitic energy load [15,26]. BM is also susceptible to undesirable mixing of unreacted gases with product gases in the reactor (back mixing) and dilution of the reaction medium due to the formation of water in the reaction (Eq. 2) [15].

There is no biologically dictated minimum load in terms of hydrogen throughput and immediate load change from 100 to 0% can be made without effecting the process [37]. Effective resumption of BM has been demonstrated after 560 hours of stagnant operation without harmful consequences, indicating high flexibility [37]. However, the practical minimum load (approximately 10%) occurs when the energy required of the stirrers exceeds that of the methane being produced [37]. A high tolerance for impurities and gas composition variation make the coupling of biogas from anaerobic digestion with BM particularly suitable [28].

2.2.2 Catalytic methanation

Catalytic methanation (CM) is a thermochemical process which takes place at high temperatures (200 - 700°C) and at higher pressures between 1-100 bar [19]. In large-scale and continuous

operations, the most common technology is the adiabatic fixed-bed reactor; smaller scale or intermittent operation (as with P2G) can be achieved with isothermal reactors [21]. The heat released must be controlled to avoid catalyst degradation and maintain a forward reaction and is also the focus of much research [15,31].

Operational flexibility is a key issue with CM as load changes may induce runaway heating or cooling of the reactors, and a complete shutdown requires flushing with an inert gas or hydrogen. A minimum load of 40% or temperature of 200°C to avoid such issues is desired, to prevent the formation of catalytic poisons, and to allow for fast restarts [15,37]. CM requires a high purity feed gas and thus biogas from anaerobic digestion must be cleaned upstream prior to use [15].

Much faster rates of production are achieved with CM as compared to BM due to the favourable conditions, presence of a catalyst, and absence of a gas-liquid mass transfer resistance [29,50]. CM processes also have a lower power requirement per unit of gas produced than that of BM [15].

Opportunities exist for CM to produce steam from the cooling circuit to pre-heat the feed gases, with sufficient energy left to run a steam turbine or use elsewhere, increasing the process efficiency and allowing for cost savings [19,26]. However, quantifying this was considered beyond the scope of this paper.

2.3 Hydrogen storage

As the electrolysers can be operated more dynamically than the methanation phase there is a need for a minimum volume of hydrogen storage as a buffer. The smaller or less dynamic the methanation units, the larger the required hydrogen storage [7,28,29,35]. Suitable methods of storage include compressed gas tanks, cryogenic compressed liquid hydrogen tanks and metal hydride storage [15].

The issues arising from operating a methanation plant intermittently could be lessened by optimising the hydrogen storage and methanation reactor volume to minimise the number of shutdowns. This would require having the shutdown and start-up costs of the system and a highly accurate estimation of the operation schedule of the electrolyser (weather and market dependent). Neither of these are readily available. The CAPEX of hydrogen storage is significant, and depending on plant setup can outweigh the methanation CAPEX. In a study by Aicher et al. the total investment cost of a P2G plant was reduced by 8.4% through dynamic operation of the methanation system lessening the hydrogen storage requirement with similar annual productions of methane achieved [51].

2.4 Source of carbon dioxide

The particular source of carbon dioxide is irrelevant in terms of the overall conversion process however BM is much more tolerant of impurities (such as H_2S) than CM. P2G could utilise the carbon dioxide content of biogas as a novel upgrading system, offsetting significant costs of traditional upgrading with the additional benefit of utilising the waste heat. Several industries generate relatively pure sources of carbon dioxide that could also potentially be used such as distilleries and wastewater treatment plants (WWTPs) [52,53]. Ideally the source of carbon dioxide would be biogenic (biogas plants, WWTPs, and distilleries) such that the methanation process is carbon neutral.

2.5 Gas quality

The high selectivity of the methanation process leads to a methane content of approximately 95% in the product gases. However, this still results in an energy content less than that of natural gas due to the lack of higher hydrocarbons [15]. In smaller quantities, the gas produced by P2G can be compressed and injected into the transmission grid without issue but in some instances the addition of propane may be required to meet the gas grid specifications, particularly when injecting into the distribution network [31,54]. Though it is possible for hydrogen to be injected directly into the gas grid several issues would arise since the existing natural gas grids were designed for methane. Hydrogen leads to much more permeation and corrosion than methane and for safety reasons the maximum hydrogen content is limited to between 0.1 and 10% by volume; depending on the country, limits up to 20% have been discussed [55–57]. The amount that can be injected is also limited by gas quality regulations, as hydrogen has approximately one third the volumetric energy content as compared to methane (12 v. 36 MJ/m^3) [54,58]. Therefore, power-to-hydrogen for grid injection requires further work to define and standardize the allowable limits and is not feasible in the short-medium term.

2.6 P2G modelling: system performance and costs

The model used in this study does not explicitly differentiate between technologies and instead uses input parameters such as cost, efficiency, energy consumption and lifetime of the parts. As indicated, in the time periods analysed, PEM electrolysis will have superior efficiency, greater ability to facilitate VRE and have greater cost reduction potential than the AEC and SOEC systems. Thus the PEM was considered most suitable for P2G [7,15,27,49] and the model proposed herein. Preliminary analysis of the likely operation schedule of an electrolyser engaging in the electricity market (as

represented by the electricity market in Ireland for this study: Appendix 2) showed that annual run hours would need to be high to minimise the LCOE. Thus, the high flexibility of BM would be somewhat negated, with the higher efficiency of CM being preferred (no stirring required and waste heat utilisation). At scales in excess of 5MW, CM technology was also found to be more economic [37]. Thus, the envisaged system in the model consisted of 10 MW_e PEM electrolysis coupled with CM. Ancillary components such as supply water purification, pumps, and electronics are included for in the balance of plant (BoP), the operational cost (OPEX) is broken into fixed and variable components.

The requirement for hydrogen storage is largely dependent on the bid strategy of the facility, and resultant intermittency of the production of the gas. Thus, a small volume of storage is included in the contingency and BoP in order to simply regulate the flow of hydrogen to the methanation process. With the high costs associated with hydrogen storage infrastructure it is was considered best to minimise this element [61]. The envisaged system for the model can thus operate part load, experience down time, and due to its bidding strategy will not go long periods without operating. Future models may have the capacity to achieve greater cost savings by integrating more hydrogen storage despite the associated high CAPEX. Table 2 illustrates the average specifications of PEM electrolysis and CM found in literature and hence used in the model.

Table 2. Electrolysis and methanation energy consumption and efficiency inputs to model

Time Period		2020	2030	2040
Electrolysis	(kWh/m^3 H_2)	4.92	4.66	4.43
	%	72	76	80
Methanation	(kWh/m^3 CH_4)	0.3 (2020 base value)	0.13 (2030 base value)	0.08 (2040 base value)
	%	72.5	73.4	73.7
Overall Efficiency	%	52.2	55.8	59.0

The whole stack efficiency of the electrolysis process is listed together with the energy consumption of the methanation process, with their corresponding percentage efficiencies for the years 2020, 2030 and 2040. The figures in Table 2 attempt to account for pumping, parasitic loads, partial load inefficiencies etc. and thus may appear conservative when compared to some past literature [8,31,35]. Valorisation of waste heat is not included. Furthermore, the technological advances have not materialised to the extent predicted in much of the literature.

The flexibility and partial load capabilities of the electrolysis and methanation processes are not included in the model, however, as the system is not set up to solely take advantage of otherwise curtailed electricity this is not of considerable concern. In reality, the run hours and energy consumed will be somewhat lower than predicted.

Table 3 contains the cost estimates for P2G obtained from literature on which the financial model in this study was based. Where it was deemed that insufficient data was available, the authors' own data was fitted. Where values were given in kW gas a conversion to kWe was achieved by dividing by 0.56, analogous to the 2030 figures for electrolysis and methanation combined efficiency, as suggested in Lehner [49]. In addition to those stated in Table 3, several other references were used to inform the estimates [6,7,15,30,46,59].

The time period costs for CAPEX, BoP and OPEX are shown in Table 4. These conservative cost estimates allow for project issues and other hidden costs that would arise on projects of this scale [51,60]. Much uncertainty remains regarding such investment costs and future costs.

Several costs are not explicitly included in the model, either because they were deemed to be specific to certain sites, too ambiguous, or already accounted for in BoP. Excluded costs include for compression costs in the event of grid injection, the cost of CO_2 (site specific), and taxes and fees for grid connection. Planning, wages, regulatory issues, and breakdowns beyond that budgeted for are also not included. The introduction of other costs increases uncertainty without additional accuracy, the conservative BoP yielded similar results without the complexity seen in other works [32]. The model also does not account for inflation, nor substantial economies of scale as previous research has shown it not to apply with units tending to be modular [26]. In Table 4 the BoP and OPEX costs of electrolysis and methanation are presented as decimal fractions of their corresponding CAPEX, as are electrolyser replacement and catalyst replaced.

Table 3. Review of literature costs for P2G systems

Electrolysis (€/kW_e)	Methanation (€/kW_e)	Project Costs (€)	Other (€)	Note	Reference
1250 (2020)	840 (2016) 280 (2030)				(E&E Consultant et al., 2014) [21]
1000 (2020) 700 (2030) 400 (2050)	840 (2016) 560 (2030) 390 (2050)	Inclusive of transport, installation, and commissioning at 10-20% CAPEX.	OPEX 1-2% (10MW) of CAPEX, more for smaller units. Cell stack replacement 50% every 40,000 hrs. Additional 50% BoP for methanation, 5-10% OPEX.	Electrolysis cost is turnkey. Maximum 10-20% scale effect.	(ENEA Consulting, 2016) [31]
800 – 1500 (2014)	200 – 1000 (2014)		500 – 800/kW_e Complete cost		(Graf, Götz, et al., 2014) [37]

			including 12hr memory is future target (2030)		
	160 – 280 (2014)			In agreement with Kinger 2012 and Sterner 2009	(Lehner et al., 2014) [49]
500 (2050)	340 (2050)		8% discount rate. OPEX of 3%.		(Ausfelder et al., 2015) [61]
1300 (2011)	100 – 700 (2011)	10% CAPEX for project, construction, and unforeseen costs	5% cost of capital	Includes for connection and design (Proton-Onsite). PEM has reduced significantly since.	(Benjaminsson et al., 2013) [26]
		5% Eng. And design, 10% contingency, 2% other.	5% working capital. OPEX is 2%. 25% of CAPEX for replacement cost of electrolysis stack every 7 years.		(Saur & Ramsden, 2011) [62]
750 (combined future costs)			6% interest rate. 4% OPEX,	25-year depreciation period	(Jentsch et al., 2014) [8]
1000 (2016) 850 (2020) 710 (2030)	1650* (2016) 400 (2020)		4% OPEX,	*Inclusive of BoP, installation etc.	(Albrecht et al., 2013) [60]
2490 (2011) 1200 (2020)		10% construction, delivery etc	4% OPEX, 7.5% interest rate	25-year depreciation period	(Smolinka et al., 2011) [35]

Year of data in brackets.

Table 4. Time period costs for CAPEX, BoP and OPEX

Time Period		**2020**			**2030**			**2040**		
		Low	**Base**	**High**	**Low**	**Base**	**High**	**Low**	**Base**	**High**
Electrolysis	**CAPEX (€/kW$_e$)**	650	850	1000	500	700	850	400	560	660
	BoP	0.1	0.15	0.2	0.1	0.15	0.2	0.1	0.15	0.2
	OPEX	0.03	0.04	0.05	0.02	0.032	0.04	0.02	0.032	0.04
Electrolyser Replacement (Years 10, 17, 24)		0.2	0.32	0.4	0.2	0.32	0.4	0.2	0.32	0.4

Methanation	**CAPEX (€/kW$_e$)**	135	160	185	110	140	170	100	125	150
	BoP	0.85	1	1.15	0.85	1	1.15	0.85	1	1.15
	OPEX	0.05	0.057	0.065	0.05	0.057	0.065	0.05	0.057	0.065
Catalyst Replacement (Year 15)		0.7	0.8	0.9	0.7	0.8	0.9	0.7	0.8	0.9

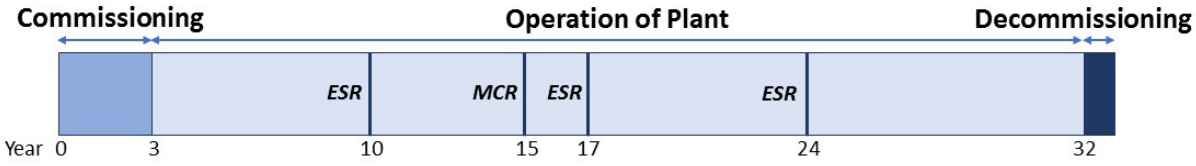
Figures for BoP, OPEX, and Replacement as expressed as decimal fraction of respective CAPEX

2.7 Model to calculate LCOE

A bespoke discounted cash flow model in MS Excel® is used to calculate the LCOE of the methane produced and the figures contained in this paper. Calculating LCOE is a standard method and was previously outlined by Visser and Held (2014) [63] and frequently referenced in past literature [33,64–68]. It allows for intuitive comparison with electricity generators and other storage methods. In this study, the LCOE represents the breakeven selling price of the gas produced and is defined as per equation 3.

$$LCOE = \frac{\sum_{i=0}^{n} \frac{Costs\ in\ year\ i}{(1+Discount\ rate)^i}}{\sum_{i=0}^{n} \frac{kWh\ of\ gas\ produced\ in\ year\ i}{(1+Discount\ rate)^i}} \qquad (3)$$

The timeline of the model is shown in Figure 2. It includes for a 3-year commissioning phase, 30 years of operation (during which the electrolysis units are replaced three times and methanation unit replaced once) and one-year decommissioning. The replacement schedule is optimised such that both the methanation plant and electrolysis stack will reach the end of their life in approximately the same year, avoiding shutting down the plant with relatively new components in place [69].



ESR – Electrolysis Stack Replacement
MCR – Methanation Catalyst Replacement

Figure 2. Lifecycle of the Plant used in the Cash Flow Model

A cost to include land purchase, permits, transport, site preparation, engineering and design costs, grid connection as well as contingency was calculated according to the equation 4, derived in Appendix 1:

$$Land\ Capital\ = €18.687(kW_e\ of\ Electrolysers) + €331{,}313 \qquad (4)$$

This would be paid in year 0. The remaining CAPEX is paid in instalments in years 0, 1, and 2 at 20%, 50%, and 30% of total CAPEX respectively. Decommissioning costs were 20% of CAPEX and paid in the final year. A discount rate of 7% was used throughout in line with much of the literature as referenced in Table 3; calculating the perceived risk to an investor is beyond the scope of this study. The cost of CO_2 was not included as this paper was written to examine the financial feasibility of locating P2G next to current sources of large quantities of rejected CO_2 (distilleries, WWTPs, biogas plants etc.). The cost of water was included without consideration of recovery of water in the methanation step.

With respect to electricity price and run hours, preliminary examination of the 2016 Irish single electricity market (SEM) indicated that a bid price of €50/MWh yielded run hours of ca. 6500 and an average electricity cost of €35/MWh (Appendix 2). Thus, these assumptions were used throughout and thought to be analogous to 2020 data.

3. Results and discussion

3.1 Levelised cost of energy of P2G

Table 5 contains the results of the model for the low, base, and high cost scenarios specified in Table 4 for the three selected time periods (2020, 2030 and 2040). Detailed calculations are set out in a spreadsheet in Supplementary Data. Taking into account the new electricity market data, updated cost estimates, and a full plant lifecycle, the results of the generated model are consistent with many found in literature [15,30,37,38,61] but within a smaller range. Comparison can be made to those outlined in Table 1.

Table 5. LCOE of the envisaged P2G system under different scenarios

Scenario	2020	2030	2040

LCOE of 10MW$_e$ plant (€/MWh) *- Bid Price of €50/MW$_e$h.* *- Average cost of electricity of €35/MW$_e$h exclusive of taxes/tariffs.* *- Run hours of 6500 p.a.* *Analogous of 2020 SEM data.*	**Low**	107	89	81
	Base	124	105	93
	High	143	121	103

3.2 Breakdown of LCOE

Hypothetically, in the 2020 base scenario, if the electricity was available at zero cost for the same number of hours, the LCOE would drop to €55/MWh. At a minimum, exclusive of CAPEX and OPEX, the methane generated in P2G systems has a cost as determined in equation 5, assuming positive or zero electricity costs.

$$Minimum\ Cost\ of\ Produced\ Gas\ (€/MWh) = \frac{Electricty\ Cost\ (€/MW_eh)}{Electrolysis\ efficiency \times Methantauion\ efficiency} \quad (5)$$

If the respective efficiencies of electrolysis and methanation are 72% and 72.5%, as in the 2020 scenario (Table 2) then the gas can be expected to be approximately double (0.72 x 0.725 = 0.52) the cost of the electricity (as per Eq. 5) plus the levelised CAPEX and OPEX costs. This illustrates the importance of sourcing low-cost electricity. Figure 3 shows the breakdown of the 2020 base scenario LCOE into its components and further highlights the importance of low-cost electricity in producing a competitively priced methane end product.

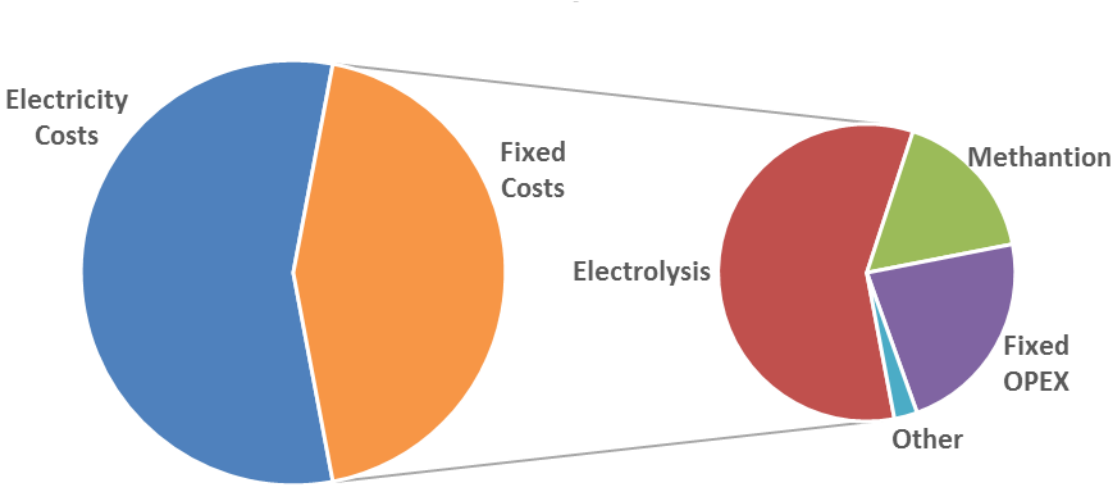


Figure 3. Breakdown of the system LCOE into its components for 2020 base scenario

As seen in Figure 3 the LCOE is dominated by electricity costs (56%) with the remainder consisting of electrolysis (25.5%), fixed OPEX (9.9%), methanation (7.4%), and other (1.1%). Thus, it can be seen that the conservative assumptions for system CAPEX and subsequent cost reductions (particularly in the electrolysis technology) over time do not impact the LCOE as considerably as may be expected; this is further demonstrated in section 3.3. Consequently, the benefits of modelling ambitious reductions are limited. Equipment being replaced/upgraded during the system's lifetime will most likely be done so at a lower cost and higher specification than when first installed, however this is unaccounted for in the model. Only in the event that efficiency improved vastly would it have a significant impact on the LCOE. As discussed in 2.1.3, if the PEM system has a 5% better efficiency (70 vs 75%) in 2020, for example, than the AEC system, it is justified to pay up to 46.6% more for a PEM electrolyser and still reduce the system LCOE under base conditions (Appendix 4). This effect is lessened with reduced annual run hours and electricity cost but exacerbated when high capacity factor and high energy costs are used.
Decommissioning is assumed to cost 20% of the CAPEX and is paid in the final year of the project; this is a conservative estimate as in reality the recyclability of the system may even command a fee.

Should P2G be used in place of traditional biogas upgrading a portion of the capital will be offset. The upgrading plant required to process an equivalent volume of carbon dioxide as the 2020 base scenario, in the form of raw biogas (assumed 60:40 methane to carbon dioxide), would cost ca. €2.45 million [70]. The model in this paper calculates a 10MW_e P2G system would cost ca. €13m in 2020, and €9m in 2040 but with a better efficiency. This equates to an investment cost of €3,018/Nm^3_{CH4}/h for traditional pressure swing adsorption (PSA) upgrading versus €10,236/Nm^3_{CH4}/h (2020) and €6,383/Nm^3_{CH4}/h (2040) for a P2G system (Appendix 3). Therefore, the increased production of biomethane from P2G upgrading would seem to justify the additional expense when compared to PSA. The profitability of this configuration will be determined by the value of the additional biomethane produced in P2G versus PSA upgrading (762 vs. 1270 Nm^3_{CH4}/h in 2020), and the plant's ability to extract value from the electrolysers.

3.3 Sensitivity analysis

Figure 4 illustrates the effect of varying the five most sensitive model parameters by +/-25% on the LCOE. The five parameters were electricty cost, run hours, total CAPEX, discount rate, and fixed OPEX.

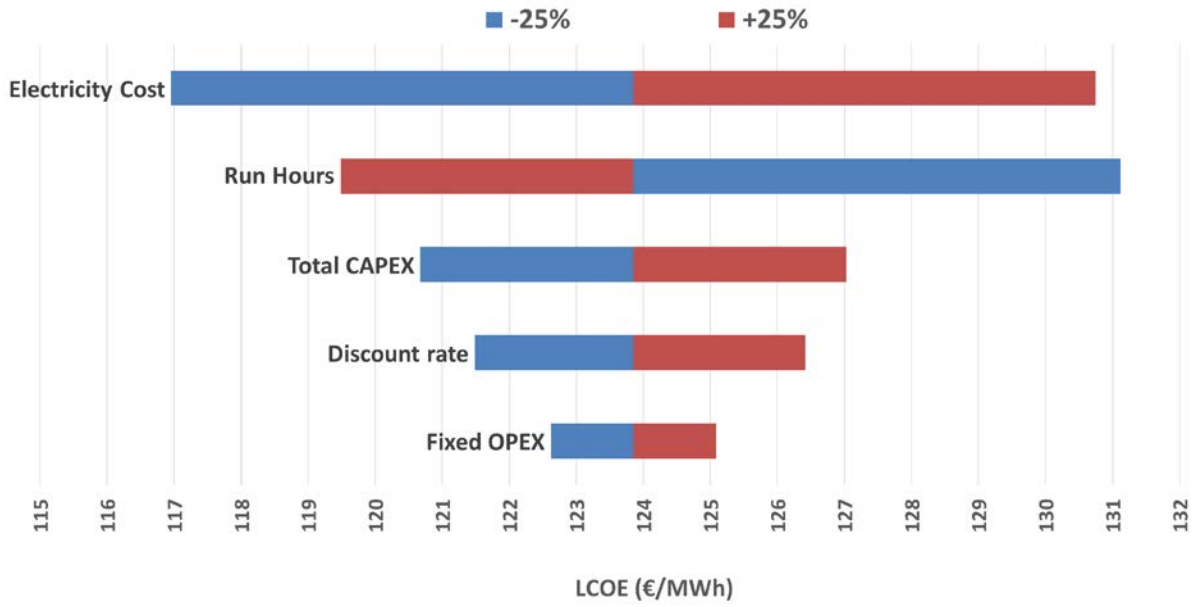


Figure 4. Sensitivity Analysis of the 2020 base scenario

Similar to Figure 3, Figure 4 illustrates that the electricity cost has the most significant effect on the LCOE, followed by run hours. Run hours are a function of the bid price and electricity market, and hence are closely related to the electricity cost. Results show that a lower capacity factor (lower run hours) coinciding with cheap electricity increases the LCOE. It was previously proposed that an increased bid price associated with longer run hours may reduce LCOE [17], and this was found to be true in this case. The benefits of paying more for the electricity and the associated increase in capacity factor outweigh the additional costs, as high run hours are required to produce sufficient quantities of gas to amortise the project cost. Thus, there is potential scope to optimise the bid strategy of P2G systems to increase the run hours and reduce the LCOE (non-linear relationship), as suggested by Vandewalle et al. [30].

It is proposed that a business model based upon the sole consumption of otherwise curtailed energy may not be viable due to the low capacity factor, even in high VRE scenarios. Considerable value would need to be placed on the grid stability function provided with the energy supplied at near zero cost. Similar conclusions were found in studies by Gotz et al. [15] and de Bucy [19].

Reductions in CAPEX and OPEX will make future projects more attractive but without considerably affecting the LCOE. Further analysis reveals that for the LCOE to fall by 20%, the total CAPEX of the system would need to drop by 76.2%, or the cost of electricity would need to fall by 35.9%.

3.4 Potential for incentivisation

The LCOE of renewable gas produced from a P2G system, as shown in Table 5, is higher than fossil fuel alternatives such as diesel transport fuel (it would be more correct to compare to other advanced biofuels but few are at a sufficient TRL to do so). Diesel retails at €105/MWh excluding value added tax (VAT) in Ireland (47.3% of which consists of other taxes) [71]. To reduce GHG emissions in the transport sector, many countries may look to introduce subsidies to incentivise advanced biofuels such as gaseous fuel from non-biological origin from P2G. In this study, the LCOE of the 2020 base scenario was calculated at €124/MWh. This would imply that an incentive of €19/MWh is required for P2G to reach price parity with diesel (if not subject to similar excise duty type taxes). This incentive can be considered modest although it is likely that the product gas will be subject to some taxes or other charges and as such the required gas sale price or incentive will be higher than quoted. However, scope exists for a modest incentive to make gaseous fuel from non-biological origin competitive with diesel. Given the low TRL of other advanced biofuels this is encouraging. In the longer term, it is highly likely that diesel will not be the competition as its use will be prohibited in many cities. Mexico, Paris and, Athens have prohibited diesel use by 2025. In essence, the end product of P2G will only be in competition with advance biofuels and electricity as a source of propulsion.

Utilising the by-products of P2G can add financial competitiveness. For example, if valorisation of the oxygen (from electrolysis) can be achieved, this could provide a significant additional income [30]. Given that there is an established demand for pure oxygen, especially within the medical industry, and with the opportunity for it to be marketed as “green” oxygen, this is not unfeasible. In Breyer et al. a value of 8c/kg O_2 (11.43c/Nm_3) was suggested [33]. In this study, if a 10c/Nm_3 profit can be achieved through the sale of oxygen, the LCOE would fall from €124 to €105/MWh (2020 base scenario).

Modern electrolysers have been shown to have the technical capacity to provide ancillary services to the grid delivering benefits to its operation [7,18,33]**.** In previous literature it has been suggested that a fee could potentially be paid by the TSO for the availability to consume energy or provide power balancing services through P2G; such a fee would again reduce the LCOE of the system [4,6,18,72,73]. In the short term, no great precedence exists for the collection of fees for these grid services however future potential has been highlighted and discussed by policymakers [4,5,10,74].

Several works have shown that it is essential in order for P2G to become competitive [5,18]. In Breyer et al. [33] a grid service payment of €35/MW_e was assumed, ultimately making the plant profitable in that scenario. This was considered a highly optimistic target given the advantages of interconnection and potential increases in the allowable limit of non-synchronous generation (VRE). A payment of €15/MW_e was chosen as a more conservative estimate for the calculations in this study. Assuming 8500 hrs availability per annum (€15/MW_e x 8500 hrs/a x 10 MW_e = €1,275,000 pa), the payment lowered the LCOE to €87/MWh.

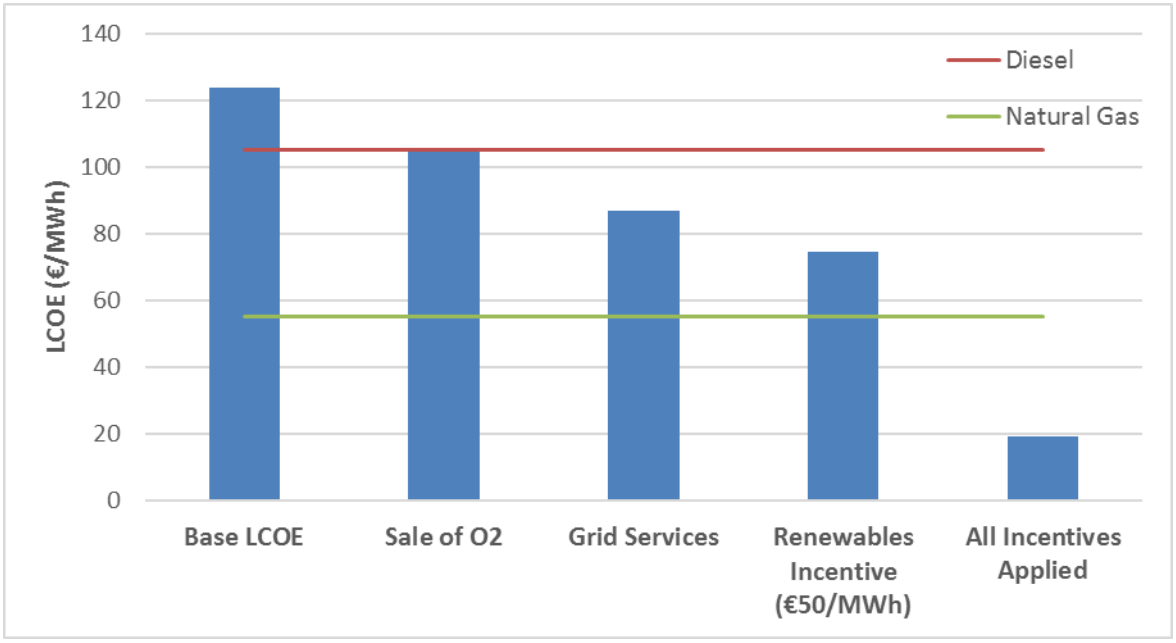


Figure 5. Effect of incentives and supplementary income on effective 2020 base system LCOE with market prices of diesel and household natural gas ex. VAT for reference

Figure 5 demonstrates how the competitiveness of gaseous fuel from non-biological origins increases with respect to diesel and household natural gas as incentives and supplementary incomes are applied. It can be seen that a combination of incentives and valorisations could potentially make the gas cheaper than its competitors, again given a favourable tax status.

4. Conclusion

The LCOE of a P2G system was found for low, base, and high cost scenarios for 2020 (€107-143), 2030 (€89-121), and 2040 (€81-103). Despite a fall in P2G capital costs, ultimately the economic viability of P2G will still be dependent on the availability of low-cost electricity. Curtailed electricity alone may not be enough. Incentives, tax exemptions, valorisation of oxygen, or exemption from grid access payments may be required in order to make P2G more financially competitive as a source of advanced transport fuel. Since P2G can facilitate additional VRE on the electricity grid it may also

receive a fee for such services. Combinations of incentives and supports would make P2G potentially much more competitive than other advanced biofuels.

Acknowledgements

This work was funded by Science Foundation Ireland (SFI) through the Centre for Marine and Renewable Energy (MaREI) under Grant No. 12/RC/2302. The work was also co-funded by Gas Networks Ireland (GNI) through the Gas Innovation Group and by ERVIA.

References

[1] Gao Y, Gao X, Zhang X. The 2 °C Global Temperature Target and the Evolution of the Long-Term Goal of Addressing Climate Change—From the United Nations Framework Convention on Climate Change to the Paris Agreement. Engineering 2017;3:272–8. doi:10.1016/J.ENG.2017.01.022.

[2] UNFCCC. Report of the Conference of the Parties on its twenty-first session, held in Paris from 30 November to 13 December 2015. vol. 1194. 2015.

[3] European Parliament. Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009. Off J Eur Union 2009;140:16–62. doi:10.3000/17252555.L_2009.140.eng.

[4] Hart D, Bertuccioli L, Hansen X. Policies for Storing Renewable Energy. 2016.

[5] Chandler H. A Guide to the Balancing Challenge. 2011. doi:612011171P1.

[6] Schiebahn S, Grube T, Robinius M, Tietze V, Kumar B, Stolten D. Power to gas: Technological overview, systems analysis and economic assessment for a case study in Germany. Int J Hydrogen Energy 2015;40:4285–94. doi:10.1016/j.ijhydene.2015.01.123.

[7] Grond L, Schulze P, Holstein J. Systems Analyses Power to Gas; deliverable 1: Technology Review. DNV Kema 2013;GCS 13.R.2:1–70.

[8] Jentsch M, Trost T, Sterner M. Optimal use of Power-to-Gas energy storage systems in an 85% renewable energy scenario. Energy Procedia 2014;46:254–61. doi:10.1016/j.egypro.2014.01.180.

[9] Mc Garrigle E V., Deane JP, Leahy PG. How much wind energy will be curtailed on the 2020 Irish power system? Renew Energy 2013;55:544–53. doi:10.1016/j.renene.2013.01.013.

[10] Bousseau P, Fesquet F, Belhomme R, Nguefeu S, Thai TC. Solutions for the Grid Integration of Wind Farms---a Survey. Wind Energy 2005;9:13–25. doi:10.1002/we.177.

[11] de Boer HS, Grond L, Moll H, Benders R. The application of power-to-gas, pumped hydro storage and compressed air energy storage in an electricity system at different wind power penetration levels. Energy 2014;72:360–70. doi:10.1016/j.energy.2014.05.047.

[12] US Energy Information Administration. International Energy Statistics n.d. https://www.eia.gov/beta/international/data/browser/#/?pa=0000000000000000000000004&c=ruvvvvvfvtvnvv1urvvvvfvvvvvvfvvvou20evvvvvvvvvvnvvuvo&ct=0&tl_id=2-A&vs=INTL.82-7-AFG-MK.A&vo=0&v=H&start=1980&end=2014 (accessed March 20, 2017).

[13] Chen H, Cong TN, Yang W, Tan C, Li Y, Ding Y. Progress in electrical energy storage system: A critical review. Prog Nat Sci 2009;19:291–312. doi:10.1016/j.pnsc.2008.07.014.

[14] Gimeno-Gutiérrez M, Lacal-Arántegui R. Assessment of the European potential for pumped hydropower energy storage : A GIS-based assessment of pumped hydropower storage potential. 2013. doi:10.2790/86815.

[15] Gotz M, Lefebvre J, Mors F, McDaniel Koch A, Graf F, Bajohr S, et al. Renewable Power-to-Gas: A technological and economic review. Renew Energy 2016;85:1371–90. doi:10.1016/j.renene.2015.07.066.

[16] Kotter E, Schneider L, Sehnke F, Ohnmeiss K, Schroer R. The future electric power system: Impact of Power-to-Gas by interacting with other renewable energy components. J Energy Storage 2016;5:113–9. doi:10.1016/j.est.2015.11.012.

[17] Ahern EP, Deane P, Persson T, Ó Gallachóir B, Murphy JD. A perspective on the potential role of renewable gas in a smart energy island system. Renew Energy 2015;78:648–56. doi:10.1016/j.renene.2015.01.048.

[18] Walker SB, Van Lanen D, Fowler M, Mukherjee U. Economic analysis with respect to Power-to-Gas energy storage with consideration of various market mechanisms. Int J Hydrogen Energy 2015;41:7754–65. doi:10.1016/j.ijhydene.2015.12.214.

[19] de Bucy J. Non-individual transport – Paving the way for renewable power-to-gas (RE-P2G). 2016.

[20] Sterner M, Stadler I. Energiespeicher - Bedarf, Technologien, Integration. Springer Berlin Heidelberg; 2014.

[21] E&E Consultant, HESPUL, Solagro. Etude portant sur l'hydrogène et la méthanation comme procédé de valorisation de l'électricité excédentaire. Cassel, France: 2014.

[22] European Commission. Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the promotion of the use of energy from renewable sources (recast) 2017;382.

[23] Walker SB, van Lanen D, Mukherjee U, Fowler M. Greenhouse gas emissions reductions from applications of Power-to-Gas in power generation. Sustain Energy Technol Assessments 2017;20:25–32. doi:10.1016/j.seta.2017.02.003.

[24] Collet P, Flottes E, Favre A, Raynal L, Pierre HH, Capela S, et al. Techno-economic and Life Cycle Assessment of methane production via biogas upgrading and power to gas technology. Appl Energy 2016;192:282–95. doi:10.1016/j.apenergy.2016.08.181.

[25] European Council. Revised Renewable Energy Directive Summary 2016.

[26] Benjaminsson G, Benjaminsson J, Rudberg R. Power-to-Gas – A technical review. SGC Rapp 2013;284:67. doi:SGC Rapport 2013:284.

[27] Rashid MM, Mesfer MK Al, Naseem H, Danish M. Hydrogen Production by Water Electrolysis: A Review of Alkaline Water Electrolysis, PEM Water Electrolysis and High Temperature Water Electrolysis. Int J Eng Adv Technol 2015:2249–8958.

[28] Graf F, Krajete A, Schmack U. Techno-ökonomische Studie zur biologischen Methanisierung bei Power-to-Gas-Konzepten 2014:61. doi:10.13140/RG.2.1.2001.9366.

[29] Rönsch S, Schneider J, Matthischke S, Schlüter M, Götz M, Lefebvre J, et al. Review on methanation – From fundamentals to current projects 2016;166:276–96.

doi:10.1016/j.fuel.2015.10.111.

[30] Vandewalle J, Bruninx K, D'Haeseleer W. Effects of large-scale power to gas conversion on the power, gas and carbon sectors and their interactions. Energy Convers Manag 2015;94:28–39. doi:10.1016/j.enconman.2015.01.038.

[31] ENEA Consulting. The Potential of Power-To-Gas 2016;33:51.

[32] Giglio E, Lanzini A, Santarelli M, Leone P. Synthetic natural gas via integrated high-temperature electrolysis and methanation: Part II-Economic analysis. J Energy Storage 2015;2:64–79. doi:10.1016/j.est.2015.06.004.

[33] Breyer C, Tsupari E, Tikka V, Vainikka P. Power-to-gas as an emerging profitable business through creating an integrated value chain. Energy Procedia 2015;73:182–9. doi:10.1016/j.egypro.2015.07.668.

[34] Genovese J, Harg K, Paster M, Turner J. Current (2009) State-of-the-Art Hydrogen Production Cost Estimate Using Water Electrolysis Independent Review. Analysis 2009:51. doi:NREL/BK-6A1-46676.

[35] Smolinka T, Günther M, Garche J. Stand und Entwicklungspotenzial der Wasserelektrolyse zur Herstellung von Wasserstoff aus regenerativen Energien. NOW-Studie 2011;2010:53.

[36] NEEDS. A Life cycle approaches to assess emerging energy technologies: generation, of the energy carrier hydrogen in context with electricity buffering generation through fuel cells 2008.

[37] Graf F, Götz M, Henel M, Schaaf T, Tichler R. Technoökonomische Studie von Power-to-Gas-Konzepten 2014.

[38] Buchholz OS, Van Der Ham AGJ, Veneman R, Brilman DWF, Kersten SRA. Power-to-Gas: Storing surplus electrical energy a design study. Energy Procedia 2014;63:7993–8009. doi:10.1016/j.egypro.2014.11.836.

[39] Vo TTQ, Xia A, Wall DM, Murphy JD. Use of surplus wind electricity in Ireland to produce compressed renewable gaseous transport fuel through biological power to gas systems. Renew Energy 2016;105:495–504. doi:10.1016/j.renene.2016.12.084.

[40] XE Currency Converter n.d. http://www.xe.com/currencyconverter/ (accessed November 18, 2016).

[41] Swedish Inflation Calculator n.d. http://bl.ocks.org/badosa/20735ba5bbecbc079d78 (accessed November 18, 2016).

[42] Dollar Inflation Calculator n.d. http://www.usinflationcalculator.com/ (accessed November 18, 2016).

[43] Zoulias E, Varkaraki E. A review on water electrolysis. Tcjst 2004;4:41–71.

[44] Hashimoto K, Kumagai N, Izumiya K, Takano H, Kato Z. The production of renewable energy in the form of methane using electrolytic hydrogen generation. Energy Sustain Soc 2014;4:17. doi:10.1186/s13705-014-0017-5.

[45] Ulleberg O, Nakken T, Eté A. The wind/hydrogen demonstration system at Utsira in Norway: Evaluation of system performance using operational data and updated hydrogen energy system modeling tools. Int J Hydrogen Energy 2010;35:1841–52. doi:10.1016/j.ijhydene.2009.10.077.

[46] Müller-Syring G, Henel M, Koppel W, Mlaker H, Sterner M, Hocher T. Entwicklung von modularen Konzepten zur Erzeugung, Speicherung und Einspeisung von Wasserstoff und Methan ins Erdgasnetz 2013.

[47] Brisse A, Schefold J, Zahid M. High temperature water electrolysis in solid oxide cells. Int J Hydrogen Energy 2008;33:5375–82. doi:10.1016/j.ijhydene.2008.07.120.

[48] Ursúa A, Gandía LM, Sanchis P. Hydrogen production from water electrolysis: Current status and future trends. Proc IEEE 2012;100:410–26. doi:10.1109/JPROC.2011.2156750.

[49] Lehner M, Tichler R, Steinmüller H, Koppe M. Power-to-Gas: Technology and Business Models. Springer International Publishing; 2014.

[50] Müller K, Fleige M, Rachow F, Schmeißer D. Sabatier based CO2-methanation of flue gas emitted by conventional power plants. Energy Procedia 2013;40:240–8. doi:10.1016/j.egypro.2013.08.028.

[51] Aicher T, Iglesias G M, Schaub G, Gotz M. Arbeitspaket 5: Betrachtungen des Gesamtsystems im Hinblick auf Dynamik und Prozessintegration, energiejwasser-praxis 65 2014.

[52] O'Shea R, Wall DM, McDonagh S, Murphy JD. The potential of power to gas to provide green gas utilising existing CO2 sources from industries, distilleries and wastewater treatment facilities. Renew Energy 2017;114:1090–100. doi:10.1016/j.renene.2017.07.097.

[53] Reiter G, Lindorfer J. Evaluating CO2 sources for power-to-gas applications-A case study for Austria. J CO2 Util 2015;10:40–9. doi:10.1016/j.jcou.2015.03.003.

[54] Gas Networks Ireland. Code of Operations. 2015.

[55] Svensson M. Biomethane standards. Green Gas Grids 2014.

[56] Melaina MW, Antonia O, Penev M. Blending Hydrogen into Natural Gas Pipeline Networks : A Review of Key Issues Blending Hydrogen into Natural Gas Pipeline Networks : A Review of Key Issues 2013:131. doi:10.2172/1068610.

[57] Ahern EP, Deane P, Persson T, Gallachoir BO, Murphy J. A perspective on the potential role of biogas in smart energy grids. Renew Energy 2015;78:648–56. doi:10.1016/j.renene.2015.01.048.

[58] DNV GL. Power-to-Gas project in Rozenburg, The Netherlands 2015.

[59] Kotter E, Schneider L, Sehnke F, Ohnmeiss K, Schroer R. Sensitivities of power-to-gas within an optimised energy system. Energy Procedia 2015;73:190–9. doi:10.1016/j.egypro.2015.07.670.

[60] Albrecht U, Altmann M, Michalski J, Raksha T, Weindorf W. Analyse der Kosten Erneuerbarer Gase. 2013.

[61] Ausfelder F, Beilmann C, Bertau M, Bruninger S, Heinzel A, Hoer R, et al. Energiespeicherung als Element einer sicheren Energieversorgung. Chemie-Ingenieur-Technik 2015;87:17–89. doi:10.1002/cite.201400183.

[62] Saur G, Ramsden T. Wind Electrolysis: Hydrogen Cost Optimisation. Natl Renew Energy Lab Publ 2011;Task No. H:14.

[63] Visser E, Held A. Methodologies for estimating Levelised Cost of Electricity (LCOE) Implementing the best practice LCoE methodology of the guidance Methodologies for estimating Levelised Cost of Electricity (LCOE). Ecofys 2014:35.

[64] Rubin ES. Understanding the pitfalls of CCS cost estimates. Int J Greenh Gas Control 2012;10:181–90. doi:10.1016/j.ijggc.2012.06.004.

[65] Edenhofer O, Pichs-Madruga R, Sokona Y, Seyboth K, Eickemeier P, Matschoss P, et al. IPCC, 2011: Summary for Policymakers. In: IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation. 2011. doi:10.5860/CHOICE.49-6309.

[66] Brouwer AS, van den Broek M, Zappa W, Turkenburg WC, Faaij A. Least-cost options for integrating intermittent renewables in low-carbon power systems. Appl Energy 2016;161:48–74. doi:10.1016/j.apenergy.2015.09.090.

[67] Short W, Packey D, Holt T. A manual for the economic evaluation of energy efficiency and renewable energy technologies. Univ Press Pacific 2005;2:120. doi:NREL/TP-462-5173.

[68] Mathieu P, Bolland O. Comparison of Costs for Natural gas Power Generation with CO2 Capture. Energy Procedia 2013;37:2406–19. doi:10.1016/j.egypro.2013.06.122.

[69] Ainscough OC, Peterson D, Miller E. Hydrogen production cost from PEM electrolysis. Ainscough,Chris Petersonm, David Miller, Eric Satyapal, Sunita 2014:1–11.

[70] Bauer F, Persson T, Hulteberg C, Tamm D. Biogas upgrading – technology overview, comparison and perspectives for the future. Biofuels, Bioprod Biorefining 2013. doi:10.1002/bbb.

[71] AA. Petrol Prices n.d. http://www.theaa.ie/aa/motoring-advice/petrol-prices.aspx (accessed April 27, 2017).

[72] Lund PD, Lindgren J, Mikkola J, Salpakari J. Review of energy system flexibility measures to enable high levels of variable renewable electricity. Renew Sustain Energy Rev 2015;45:785–807. doi:10.1016/j.rser.2015.01.057.

[73] Qadrdan M, Abeysekera M, Chaudry M, Wu J, Jenkins N. Role of power-to-gas in an integrated gas and electricity system in Great Britain. Int J Hydrogen Energy 2015;40:5763–75. doi:10.1016/j.ijhydene.2015.03.004.

[74] IEA. Solar Photovoltaic Energy. Technol Roadmap 2014:60. doi:10.1007/SpringerReference_7300.

Appendices

Appendix 1 – Calculation of Land Capital cost (Equation 4)

In reviewing the literature no standard calculation for the costs of land purchase, site preparation, planning, permits, etc. was apparent [63][32]. Estimates were found to vary from 15% of total CAPEX to 30% of installed CAPEX [31] but did not account for all anticipated costs. Other literature used to inform the calculation includes [69][62][36]. A minimum of €350,000 for a 1MW plant, up to a maximum of €2.2m for a 100MW plant was identified for projects of this nature. This information was used to construct a graph and derive an approximate equation for "Land Capital" cost based upon the capacity of electrolyser being installed.

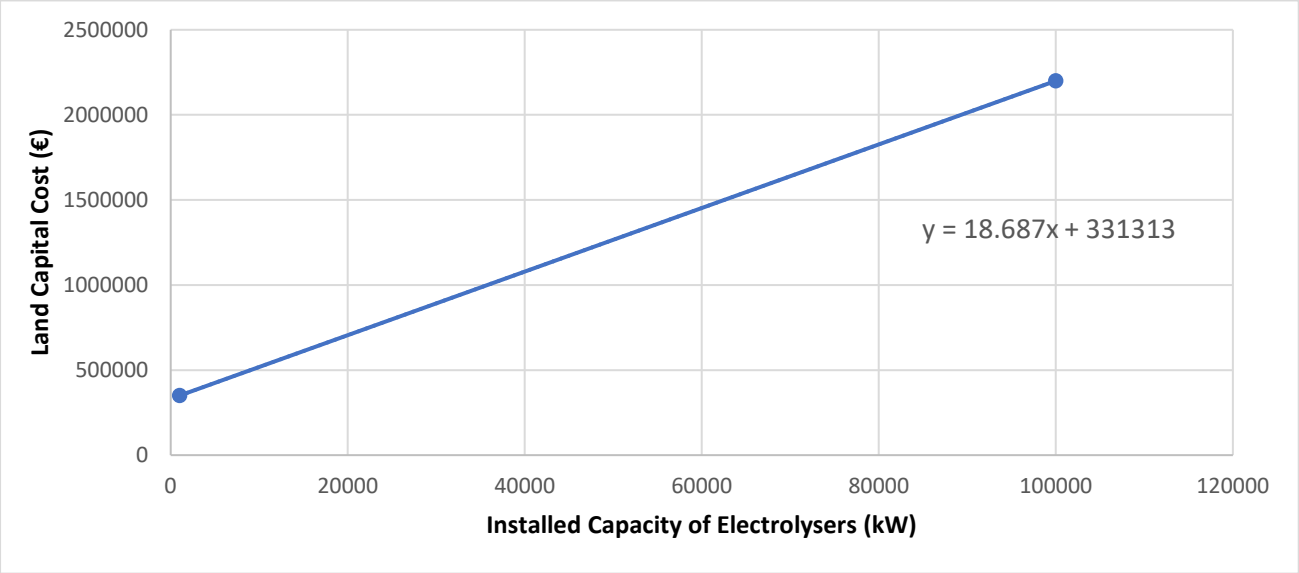


Figure 6. Land Capital cost as a function of installed electrolyser capacity

A straight-line relationship was assumed between the two points and the equation shown was used in the model.

Appendix 2 – Derivation of Electricity Market Data (Section 2.8)

"With respect to electricity price and run hours, preliminary examination of the 2016 Irish single electricity market (SEM) indicated that a bid price of €50/MWh yielded run hours of ca. 6500 and an average electricity cost of €35/MWh. Thus, these assumptions were used throughout and thought to be analogous to 2020 data" From section 2.8.

Data for the 2016 Irish electricity market was downloaded from http://www.sem-o.com/

System marginal price (SMP) is the island wide price of electricity at each half hour interval.

The number of run hours at a given bid price was found using the formula below.

$$Run\ Hours = \frac{\sum Half\ hourly\ intervals\ for\ which\ SMP < Bid\ price}{2}$$

Average cost of the electricity was given by

$$Average\ Electricty\ Cost = \frac{\sum SMP\ of\ Intervals\ for\ which\ SMP < Bid\ Price}{\sum Number\ of\ intervals\ for\ which\ SMP < Bid\ Price}$$

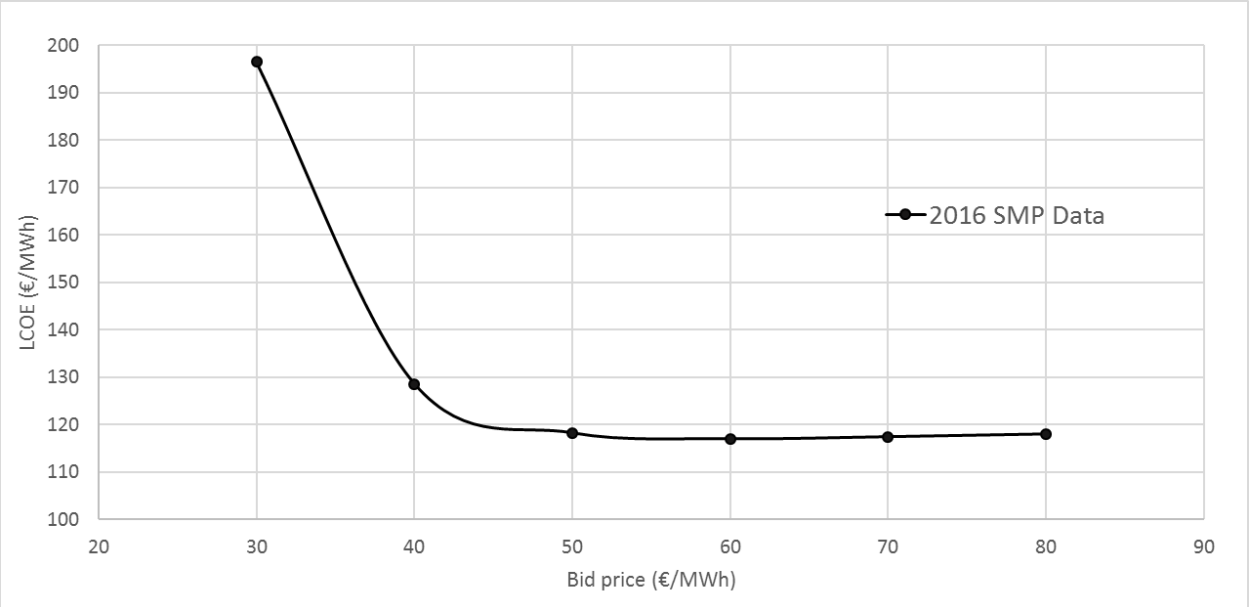


Figure 7. Change in LCOE of a P2G system with respect to changing bid price for the 2016 Irish electricity market.

When data for run hours and average cost of electricity based upon a given bid price was fed into the model and plotted (as in Figure 7) it was found that a bid price of €50/MWh approximately minimised LCOE. This corresponded to an average cost of electricity of approximately €35/MWh and run hours of 7080. The figure used for run hours was slightly reduced to 6500 to reflect the fact an

actual plant would not be perfectly flexible and have the ability to ramp up and down to take advantage of each half hour at which the SMP was less than the bid price.

Appendix 3 – Investment cost of Upgrading versus P2G (Section 3.2)

$$10MW\ electrolyser\ @\ 72\%\ \eta\ \rightarrow\ 7200\ kWh\ H_2/hour$$

$$7200\ kWh\ H_2\ @\ 3.54\ kWh/m^3\ \rightarrow\ 2033 m^3\ \ H_2/hour$$

$$2033\ m^3\ \ H_2 \xrightarrow[4{:}1\ H_2{:}CO_2]{} 508\ m^3\ \ CO_2/hour$$

$$508\ m^3\ \ CO_2/hour \xrightarrow[Biogas\ @\ 60{:}40\ CH_4{:}CO_2]{} 1270 m^3\ \ Biogas/hour$$

Thus, a 10MW P2G system can upgrade 1270m^3 of biogas per hour. Traditional pressure swing absorption (PSA) upgrading costs ca. €1800/m^3 at this scale, ca. €2.3m suitable sized plant here [70]. The model in this paper calculates a 10MW P2G system would cost ca. €13m in 2020, and ca. €9m in 2040 but with a better efficiency. As the P2G system will result in higher volumes of CH_4 being produced it is fairer to compare them on an investment cost per unit of gas produced basis.

Results:

PSA:	$€2.3m\ \div\ 762m^3\ CH_4/hour$ =	€3018/$m^3\ CH_4/hour$
P2G:		
72% η in 2020:	$€13m\ \div\ 1270m^3\ CH_4/hour$ =	*€10236/$m^3\ CH_4/hour$*
80% η in 2040:	$€9m\ \div\ 1410m^3\ CH_4/hour$ =	€6383/$m^3\ CH_4/hour$

Appendix 4 – AEC vs. PEM (Section 3.2)

"As discussed in 2.1.3, if the PEM system has a 5% better efficiency (70 vs 75%) in 2020, for example, than the AEC system, it is justified to pay up to 46.6% more for a PEM electrolyser and still reduce the system LCOE under base conditions." From section 3.2.

Under 2020 base conditions:

Electrolysis η of 70% (AEC) - LCOE of €127.27

Electrolysis η of 75% (PEM) - LCOE of €119.05

Using the goal seek function of Excel we can vary the CAPEX of the electrolyser to match the LCOE of €127.27 while maintaining the 75% η of PEM. This gives a value of €1246.8/kW compared to €850/kW in the base case, 46.7% higher.

I.e. A PEM system at 75% η will produce the same LCOE as an AEC system at 70% in the event that their CAPEXs are €1246.8/kW and €850/kW respectively.

Thus, the increased η of PEM is preferred provided it is no more than 46.6% more expensive than the AEC system, when reducing the LCOE is one's goal. As the model in this paper calculates BoP as a fraction of CAPEX, should BoP remain unchanged between the two scenarios this figure would become greater still.